MODELLING OF CARBON DIOXIDE SEQUESTRATION IN COALBEDS: A NUMERICAL CHALLENGE

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ABSTRACT

Recently, the necessity to reduce greenhouse gas emissions has provided a dual role for deep unminable coalbeds: as a source of natural gas and as a repository for carbon dioxide (CO_2), a greenhouse gas. In the process of CO_2 sequestration in coalbeds, the injected CO_2 is stored in the coalbed by sorption to the coal surface. The mechanism is that CO_2 displaces the sorbed methane (CH_4) from the coal surface that results in the enhancement of the coalbed methane (CGM) recovery.

Numerical models are a useful tool in the development of the CO_2 sequestration / CBM recovery technology. A full understanding of all of the process mechanisms is essential to performing a numerical modeling of the process. Although existing numerical models are successfully used to predict field performance of the primary CBM recovery process, many researchers still report that the recovery process is extremely complex and not fully understood. Things become even more complex in the enhanced coalbed methane (ECBM) recovery processes with CO_2 or any other gas injection. It is believed that existing numerical models do not correctly model the ECBM process mechanisms based on observation from field pilots performed by the Alberta Research Council (ARC) in Fenn Big Valley, Alberta, Canada.

The current paper describes the challenges in numerical modeling of the CO_2 sequestration / ECBM recovery process and recommends improvement in future model development.

INTRODUCTION

The injection of carbon dioxide (CO_2) in coalbeds is probably the most attractive option of all underground CO_2 sequestration or storage possibilities: the CO_2 is stored and at the same time the recovery of coalbed methane (CBM) is enhanced. The revenue of methane (CH_4) production can offset the expenditures of the storage operation.

Coalbeds are characterized by their dual porosity: they contain both primary (micropore and mesopore) and secondary (macropore and natural fracture) porosity system. The primary porosity system contains the vast majority of the gas-in-place volume while the secondary porosity system provides the conduit for mass transfer to well. Primary porosity gas storage is dominated by sorption. The primary porosity system is relatively impermeable due to the small pore size. Mass transfer for each gas molecular species is dominated by diffusion that is driven by the concentration gradient. Flow through the secondary porosity system is dominated by Darcy flow that relates flow rate to permeability and pressure gradient.

Figure 1 illustrates the overall process of gas storage and the movement through coalbeds. The primary CBM process begins with a production well that is often stimulated by hydraulic fracturing to connect the wellbore to the coal natural fracture system via an induced fracture. When the pressure in the well is reduced by opening the well on the surface or by pumping water from the well, the pressure in the induced fracture is reduced that in turn reduces the pressure in the coal natural fracture system. Gas and water begin moving through the natural and induced fractures in the direction of decreasing pressure. When the natural fracture system pressure drops, gas molecules desorb from the primary-secondary porosity interface and are released into the secondary porosity system. As a result, the sorbed gas concentration in the primary porosity system near the natural fractures is reduced. This reduction creates a concentration gradient that results in mass transfer by diffusion through the micro and mesoporosity. Sorbed gas continues to be released as the pressure is reduced.

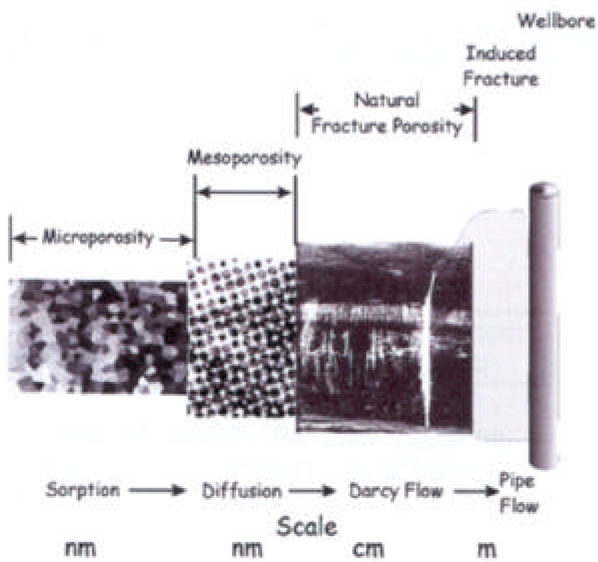

Figure 1: Coal storage and flow mechanisms

When CO_2 that is more strongly adsorbable than CH_4 is injected into the coal natural fracture system during the ECBM recovery process, it is preferentially sorbed into the primary porosity system. Upon sorption, the CO_2 drives CH_4 from the primary porosity into the secondary porosity system. The secondary porosity pressure is increased due to CO_2 injection and the CH_4 flows to production wells. The CO_2 is sequestrated in-situ and is not produced unless the injected gas front reaches the production wells. The ECBM process is terminated at CO_2 breakthrough.

An alternative in CO_2 sequestration is to inject flue gas, a mixture of CO_2 and nitrogen (N_2) to avoid the high cost of gas separation to obtain the pure CO_2 injection gas. When N_2, a weakly adsorbable gas, enters the natural fracture system, the partial pressure of CH_4 is reduced to very low levels. When the partial pressure is reduced, the desorption rate of CH_4 increases dramatically. The CH_4 is then swept along with the N_2 through the secondary porosity to the production wells. Some N_2 is sorbed into the primary porosity system but there is a net reduction in the gas content of the primary porosity system. The N_2 is produced with the CH_4 and must be separated from the CH_4 for sales.

A full understanding of all the complicated mechanisms involved in the CO_2 sequestration / ECBM recovery process is essential to have more confidence in the numerical modeling of the process. The current paper describes the challenges in numerical modeling of the CO_2 sequestration / ECBM recovery process and recommends improvement in future model development.

NUMERICAL MODELS

Seidle an ARRI (1990) have shown that conventional oil and gas numerical models can be used for primary CBM recovery process, provided that the diffusion of CH_4 from the primary porosity system into the natural fracture system of the coal is much faster than Darcy flow through the natural fractures into the production well. Since then, many commercial and research numerical models have been developed to model primary CBM recovery process with many important features such as: (1) a dual porosity system; (2) Darcy flow in the natural fracture system; (3) pure gas diffusion and sorption in the primary porosity system; and (4) coal shrinkage due to gas desorption; taken into consideration. A general description of the two types of numerical models is given in Table 1.

Table 1: Numerical models for CBM recovery process

Parameters	**Conventional Oil & Gas Models**	**Coalbed Methane Models**
Naturally Fractured Reservoir	Single porosity	Dual porosity
Physics of Gas Flow in Natural Fracture System	Darcy flow (Multiple gas components)	Darcy flow (Limited gas components)
Physics of Gas Flow between Primary / Secondary Porosity Systems	Gas flow instantaneously	Fick's law for diffusion
Gas Sorption	Sorption described by equilibrium K-values (Coal as immobile oil)	Sorption described by Langmuir isotherms

We have evaluated five numerical models for their capability to model the CBM recovery processes: (1) STARS – Computer Modelling Group (CMG) Ltd., Canada; (2) GCOMP – BP-Amoco, U.S.A.' (3) ECLIPSE – Schlumberger GeoQuest, U.K.; (4) COALGAS – Schlumberger GeoQuest, U.K.; and (5) SIMED II – Commonwealth Scientific and Industrial Research Organization (CSIRO), Australia. STARS and GCOMP are conventional oil and gas models converted to model the CBM recovery processes. At the present time, COALGAS being a single gas component model is only capable to model the primary CBM recovery process; while ECLIPSE being a two-gas component model is only capable to model the ECBM recovery process with pure CO_2 or N_2 injection.

Numerical Modelling of ECBM Processes in a Commercial-Scale 5-Spot Pattern

Numerical models are used to predict the ECBM recovery performance in a 160-acre 5-spot pattern located at the Fenn Big Valley area of Alberta, Canada. A two-dimensional areal rectangular grid system with 2,401 grid blocks (49 x 49) is used to represent ¼ of the 5-spot pattern (i.e., the smallest element of symmetry). The grid block sizes are based on an exponential stretch, which allows increasing resolution near the well.

Three cases are studied: (1) primary production for 10 years; (2) continuous CO_2 injection for 10 years at a constant injection rate; and (3) continuous N_2 injection for 10 years at a constant injection rate. The predicted CH_4 production rates (which have been normalized) and CH_4 compositions in the produced gas streams using STARS and ECLIPSE are shown in Figs. 2 and 3 respectively. It is found that the predictions by STARS (solid curves) and ECLIPSE (dashed curves) were in general agreement. This indicates that current numerical models have very similar performance even though they use two very different modelling approaches as shown in Table 1.

N_2 injection rapidly increases the CH_4 production rate. In general N_2 breakthrough at the production well occurs at about half the time required to reach the maximum CH_4 production rate. The N_2 content of the produced gas continues to increase until it becomes excessive, i.e., 50% or greater, at the point illustrated in Fig. 3. The process would usually be terminated at this point due to commercial constraints, i.e., cost of N_2 rejection and the reduction in saleable CH_4. On the other hand, the production increase due to CO_2 injection takes longer to develop than for the N_2 injection. This is due to sorption of CO_2 relatively near the well with the sorbed CO_2-CH_4 front growing out from the injection well. Eventually, CO_2 breaks through into the production well when sufficient CO_2 has been injected. At breakthrough in a homogeneous coalbed, there is little CH_4 left in the coalbed and the process is terminated. Figure 4 shows the CO_2 and N_2 distributions at different times during injection predicted by STARS.

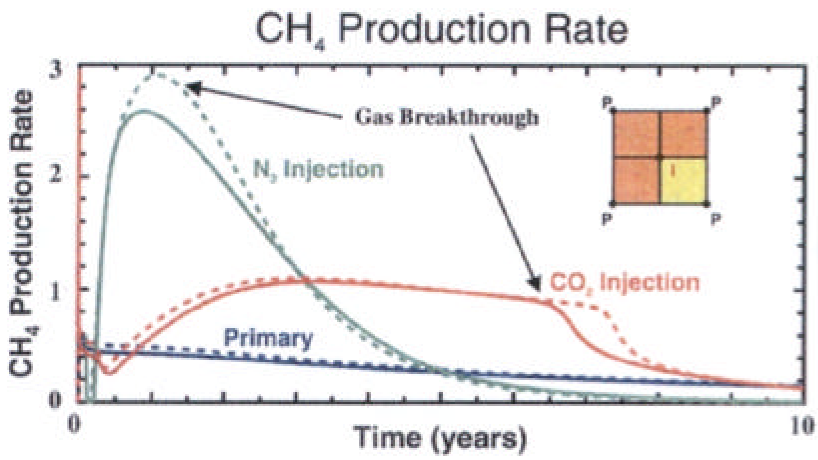

Figure 2: Predicted methane production rates

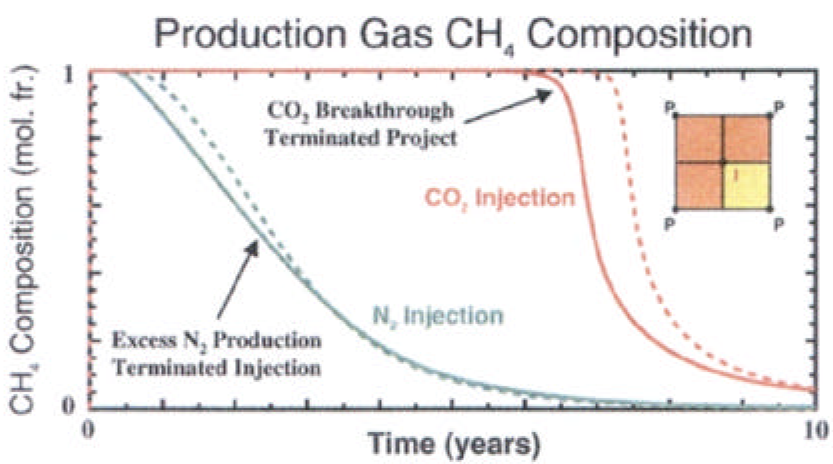

Figure 3: Predicted methane compositions in produced gas streams

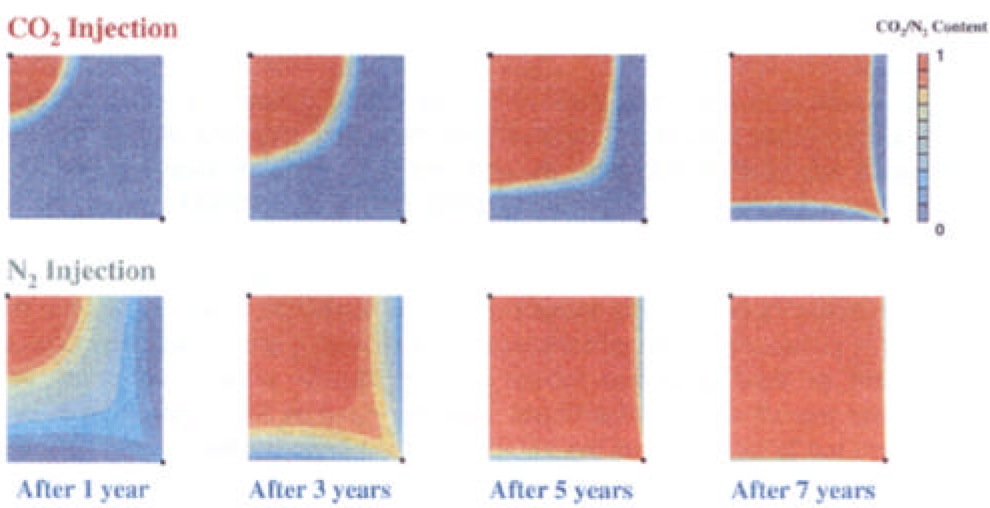

Figure 4: Predicted carbon dioxide and nitrogen distributions

FIELD MICRO-PILOT TESTS

The Alberta Research Council (ARC) is currently leading an international consortium of government and industry partners to perform micro-pilot tests with N_2, CO_2 and flue gas injection into the Cretaceous Mannville coals located in the Fenn Big Valley area of Alberta, Canada (Wong and Gunter, 1999). Excellent data of bottom-hole pressures, gas production rates and production gas compositions are being obtained.

Current numerical models are capable of history matching the field bottom-hole pressures during gas production, well shut-in and gas injection periods when gas production and injection rates are specified. However, none of the numerical models are capable of history matching the gas compositions in the produced gas streams. It is believed that the numerical models do not correctly model the multiple gas sorption and diffusion processes that account for gas storage and movement through the coalbeds. In addition, these numerical models do not model the change in coal matrix volume (swelling/shrinkage) due to sorption/desorption of gas that results in alteration in the permeability of the natural fracture system. Better understanding of these process mechanisms in both the field and in the laboratory will lead to the improvement of the numerical models.

MODELLING IMPROVEMENT

In order for a numerical model to correctly model the CO_2 sequestration/ECBM recovery process, it should have the following features: (1) all basic requirements of a commercial coalbed methane model for primary CBM recovery; (2) multiple gas components for flue gas injection; (3) coal swelling due to CO_2 sorption on coal; (4) mixed gas sorption; (5) mixed gas diffusion; and (6) thermal effect for gas injection.

Multiple Gas Components

This feature is common for the oil and gas compositional models but may not be present in the coalbed methane models developed for primary CBM recovery process only. Coal gas, often referred to as "coalbed methane", consists of CH_4, with lesser amount of heavier hydrocarbon gases such as ethane (C_2H_6) and propane (C_3H_8), as well as inorganic gases such as CO_2 and N_2. On the other hand, injected gas such as flue gas is a mixture of CO_2 and N_2 with lesser amount of oxygen (O_2), as well as other impurities (e.g., NO_x, SO_2 and SO_3). A numerical model should have the capability to handle at least three gas components such as CH_4, CO_2 and N_2.

Coal Swelling and Shrinkage

It has been shown only recently in the field that extraction of CH_4 or injection of CO_2 changes the absolute permeability of coalbeds. Mavor and Vaugh (1998) measured and interpreted data that conclusively show that production of gas from Fruitland Formation coal seams in the San Juan Basin, Colorado, U.S.A. increases coal seam permeability due to coal shrinkage. Experience from the ARC micro-pilot tests indicates that injection of pure CO_2 reduces the permeability of the Manville coal seams in Alberta, Canada due to coal swelling.

Permeability alteration is usually considered as a function of effective stress only (i.e., dilation/re-compaction model) in many numerical models. Palmer and Mansoori (1996) presented a new theoretical model for calculating pore volume compressibility and permeability in coal as a function of effective stress and matrix shrinkage. This model has been used to history match field observations in a primary CBM recovery process. Modification of the Palmer and Mansoori model with the consideration of porosity and permeability in coal as a function of not only effective stress but also sorbed gas content has the potential to model the coal swelling / shrinkage correctly in the CO_2 sequestration / ECBM recovery process.

Mixed Gas Sorption

Arri et al. (1992) and Hall et al. (1994) have demonstrated that various models such as Langmuir, two-dimensional equation of state (EOS) and ideal adsorbed solution (IAS) models all perform well for pure-gas adsorption; however, results are less satisfactory for mixtures. Of particular interest is the fact that at a pressure above its critical pressure, the pure CO_2 sorption rises rapidly and shows non-Langmir sorption behaviour. Such behaviour is characteristic of multiplayer sorption, ad this could have important implications if CO_2 is considered for injection into deep (high pressure) coalbeds. Better understanding of the sorption behaviour of gas mixtures especially mixtures with CO_2 is essential in the numerical modelling of the CO_2 sequestration / ECBM recovery process.

Mixed Gas Diffusion

Mixed gas diffusion in coal is not well understood. Crosdale (1999) suggest that the hysteresis observed during sorption / desorption of a CH_4-CO_2 mixture in Sydney Basin coal, Australia could be explained by mixed gas diffusion processes in which the molecular weight of the gas is an important consideration. Better understanding of the diffusion process of gas mixtures especially that causes the hysteresis effect of mixed gas sorption / desorption is essential in the numerical modelling of the CO_2 sequestration / ECBM recovery process.

CONCLUSIONS

The mechanisms in the CO_2 sequestration / ECBM recovery process are extremely complicated and their interactions are not fully understood. Although current numerical models are capable to model the primary CBM recovery process, they do not correctly model the ECBM recovery processes. Better understanding of the mixed gas sorption / desorption on coal, mixed gas diffusion in the coal matrix and coal swelling / shrinkage due to gas sorption / desorption in both the field and the laboratory is needed for the improvement of the numerical models.

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